QUEENSLAND FARMERS' FEDERATION
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Submission

11 May 2018

General Manager Regulation and Pricing
Energy Queensland
GPO Box 1461
BRISBANE QLD 4001

Via email: tariffs@energyq.com.au

Dear Sir/Madam

Re: Network Tariffs 2020-25 Customer Consultation Issues Paper April 2018

The Queensland Farmers' Federation (QFF) is the united voice of intensive agriculture in Queensland. It is a federation that represents the interests of peak state and national agriculture industry organisations, which in turn collectively represent more than 13,000 primary producers across the state. QFF engages in a broad range of economic, social, environmental and regional issues of strategic importance to the productivity, sustainability and growth of the agricultural sector. QFF's mission is to secure a strong and sustainable future for Queensland farmers by representing the common interests of our member organisations:

- CANEGROWERS
- Cotton Australia
- Growcom
- Nursery & Garden Industry Queensland (NGIQ)
- Queensland Chicken Growers Association (QCGA)
- Queensland Dairyfarmers' Organisation (QDO)
- Australian Cane Farmers Association (ACFA)
- Flower Association
- Pork Queensland Inc.
- Queensland United Egg Producers (QUEP)
- Bundaberg Regional Irrigators Group (BRIG)
- Burdekin River Irrigation Area Irrigators Ltd (BRIA)
- Central Downs Irrigators Ltd (CDIL)
- Pioneer Valley Water Cooperative Ltd (PV Water)
- Queensland Chicken Meat Council (QCMC).

QFF welcomes the opportunity to provide comment on the Network Tariffs 2020-25 Customer Consultation Issues Paper April 2018. QFF provides this submission without prejudice to any additional submission provided by our members or individual farmers.

Background

Irrigation electricity tariffs in Queensland have risen a minimum of 136 per cent over the past decade, and for some more than 200 per cent, while CPI has increased by just 24 per cent over the same period. Post 2020, these specific 'non-cost reflective' (transitional) irrigation and small business tariffs will be withdrawn in Queensland.

Farming businesses already struggling to cope with unsustainable electricity price increases will be unable to continue operation when this occurs. At the end of 2016, there were about 42,000 regional businesses currently on eight different tariffs classified as transitional or obsolete. About 17,400 of these connections are for farming and irrigation purposes[1 2].

The impacts of rising electricity prices are clearly eroding the competitiveness of Queensland's intensive agriculture sector and are having real implications for farm businesses and regional communities. In irrigated agriculture, there is a growing number of primary producers switching to dryland farming practices as the price of electricity has already become unsustainable for many businesses. Electricity costs are resulting in a steady decline in the number of irrigation businesses as well as reduced productivity across the sector.

In response to price increases, farming businesses, including irrigators, have been installing energy efficiency measures and renewable energy and, in many cases, simply reducing demand. Much of these gains however, have been diminished by the increasing electricity costs; whilst simply reducing demand has also come at a cost either through reduced productivity or farmers simply choosing not to plant a crop. It is essential that businesses can measure and manage their electricity use, particularly for time-of-use and seasonal-time-of-use tariffs.

QFF continues to call for appropriate metering and billing for agricultural users, so that they can make business decisions and provide business cases for future tariff selection, and to increase their productivity.

Ergon's demand tariffs

QFF maintains that the current demand tariff options are broadly unsuitable for Queensland's agricultural sector – including those who need to draw power continuously for refrigeration or animal welfare, through to those who need to draw power for milking and irrigation regardless of season or time of use penalties.

The demand charge is based on the maximum power drawn from the network each month. This response concentrates on the demand charges, as these charges reflect Ergon's long run marginal cost (LRMC), which have been estimated by Ergon to reflect:

- the majority of fixed costs and, therefore, fixed revenues
- the majority of Ergon's total revenues.

The residual fixed costs (connection charge) and variable costs are the cost requirements of Ergon after accounting for revenue from the demand charge (Table 1).

[1] 1 Queensland Productivity Commission. (2016). Electricity Pricing Inquiry 2016. Chapter 10: Rural and Regional Industries – Transitional and Obsolete Tariffs

[2] Queensland Government (2016), Queensland Government response to the Queensland Productivity Commission Electricity Pricing Inquiry, November 2016.

Table 1: Ergon network tariff components

Tariff component	Cost recovered	Charging basis
Demand charge	Long run marginal cost = majority of Ergon's fixed costs / fixed revenue	Variable charge, based on maximum monthly power demand (in kW)
Connection charge	Residual fixed costs (the balance of the fixed revenues)	Fixed annual charge
Usage charge	Variable costs (costs that change with energy usage = allowable variable revenues)	Variable charge, based on energy use (per kWh)

The application of demand tariffs will have an impact on the energy bills of agricultural customers. For example, where a farm business has high demand / high instantaneous requirements (e.g. from large pumps), but relatively low energy use, the electricity bills are likely to increase materially with the introduction of demand tariffs in 2020 or 2022.

Specific Examples

Irrigation Schemes

As part of the local management arrangements for SunWater's distribution schemes, Ergon provided energy bill information for 49 pump stations. We have used one of the pump stations in Eton's distribution network to illustrate the potential impact of transition to demand tariffs.

Eton is flagged to move from tariff 62 (usage-based), which is being phased out, to tariff 45 (a large-business demand-based tariff). Despite energy use falling below the 100 kWh threshold for tariff 45, Ergon has identified tariff 62 for the Eton pump station because of the high power demand. Ergon forecasts that as a result of Eton moving to the demand tariff, the pump station's energy bill will be 228 per cent of the bill under tariff 62.

For customers such as the Eton pump station, who have high demand and low usage, the application of demand tariffs will result in a negative impact.

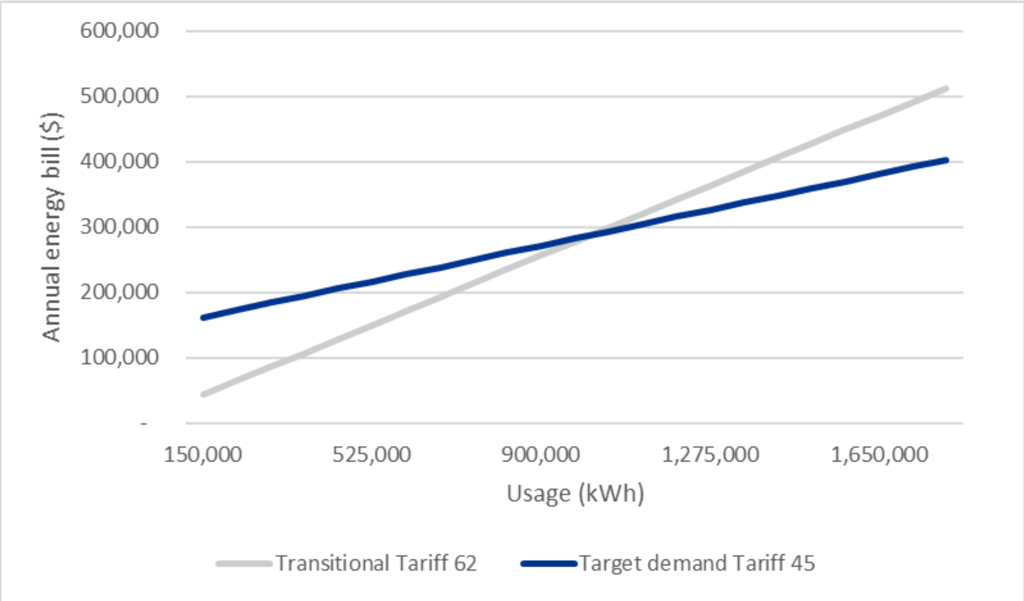
This timing of this impact will be particularly significant to irrigators as we enter a new 'price path period' for bulk water in Queensland. It is QFF's understanding that the draft referral notice (pursuant to the *Queensland Competition Authority Act 1997*) permits the pass-through of electricity prices to water users in SunWater and SEQWater schemes.

General impact of tariff 45

Figure 1 below shows the general impact on an electricity customer with a power requirement of 200 kW who move from (transitional) tariff 62 to (demand-based) tariff 45. Moving to tariff 45 has the following implications:

- For low usage (150,000kWh), the new electricity bill is higher under tariff 45 than under tariff 62.
- For energy usage of around 1,000,000 kWh, there is little change in the bill.
- For energy usage above 1,000,000 kWh, there is a reduction in the bill under demand tariff 45.

Figure 1 : Impact of Tariff 45 on electricity customer with 200kW power requirement

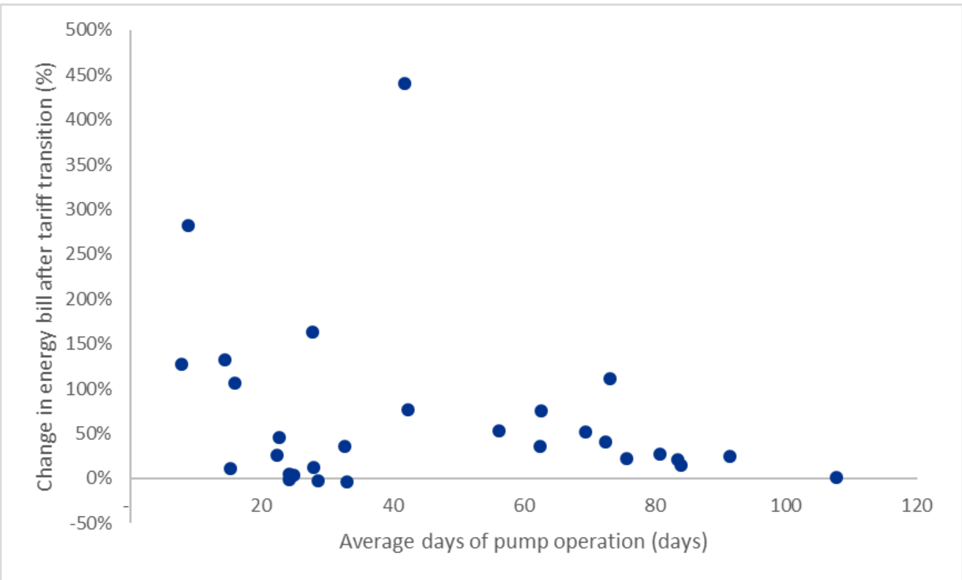


Demand tariffs favour low instantaneous power requirements, and given Ergon's allowed fixed revenues, effectively reward higher energy use. By contrast, the demand-based tariffs allocate a higher cost to high instantaneous power needs, but with low energy use, bills are higher.

Impact on transitioning SunWater distribution pump stations

Figure 2 below shows the impact across transitioning SunWater distribution pump stations. It clearly shows the weak trend that as energy usage increases, there is a smaller increase to the annual bill following transition. None of the pump stations have an energy use above the 200-day threshold to become a winner, when using demand tariff 45. Most pump stations will incur higher overall electricity bills due to the introduction of demand tariffs. Shorter pumping days (or low energy use in kWh) tend to be associated with higher bill increases.

Figure 2 : Change in energy bill after transitioning, per number of pump operating days



Demand charge and long-run marginal costs

Ergon's demand charges are based on its LRMCs, which express the costs of satisfying extra demand on the network. If there is spare capacity in the network, satisfying extra demand will incur short-run costs. In the long run, satisfying extra demand requires augmentation of the network capacity. To reflect the long-run or long-term costs, the LRMC consider capital programs and demand forecasts into the future.

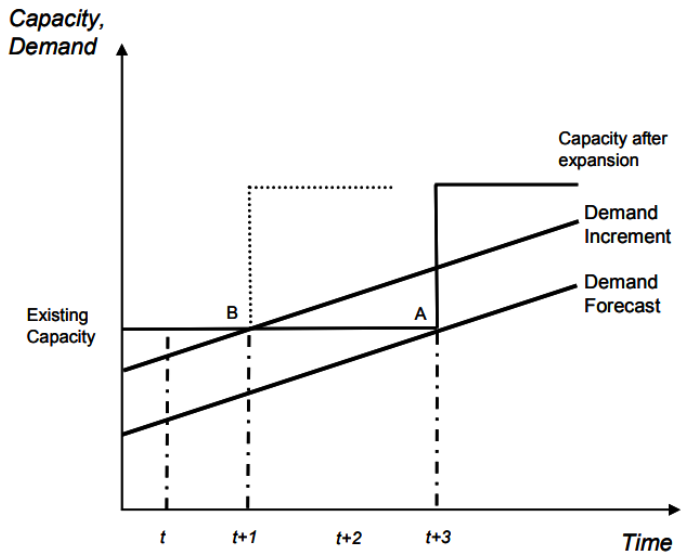
Ergon uses the annual incremental cost (AIC) approach to calculate the LRMC. The AIC is:

- present value of growth capital costs plus present value of growth operating costs divided by present value of annual demand growth.

Figure 3 below shows the concept of LRMC when applied to pricing. If the LRMC are lower than the value consumers place on demand, demand for electricity will increase (expansion will occur). Forecasts of demand into the future will increase if the same demand growth rate applies. At some point the extra demand will require network expansions sooner, increasing the present value of growth capital costs. This will increase the LRMC until they match how much consumers value network capacity.

Conversely, if the LRMC are higher than consumers value electricity, demand will decrease until the LRMC match demand.

Figure 3: Effect of increasing demand on network expansions



Ergon's calculation of long run marginal costs

Ergon's demand charge is based on LRMC derived from the Ergon-proposed (and AER-approved) forward capital program.

Ergon has five categories of direct capital costs, shown in Figure 4 (below), which shows the average portions of approved annual capex between 2015–16 and 2019–20. Ergon's total average annual capital expenditure over the 2015–16 to 2019–20 period was forecast to be $572 million.

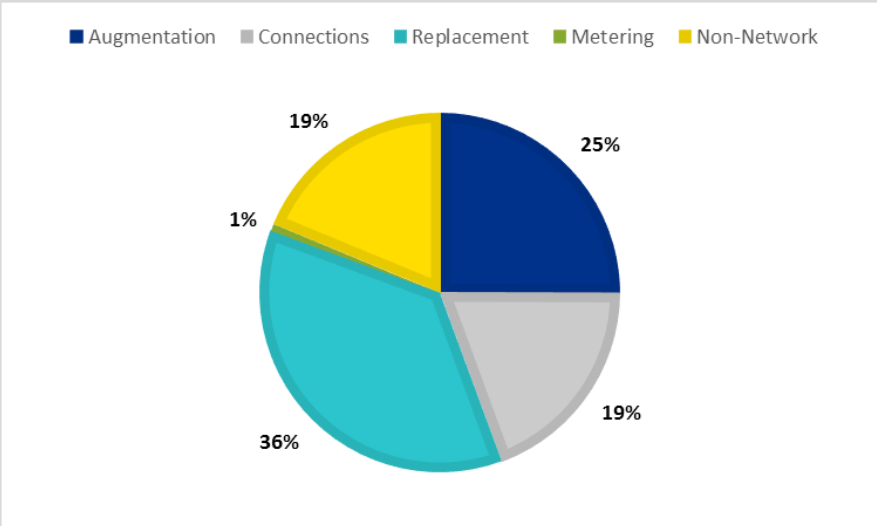
Ergon attributes a portion of its annual capital expenditure to demand growth, which is then used in the calculation of LRMC.[3] Ergon's apportionment to demand growth is:

- 100 per cent of augmentation capital expenditure

[3] Ergon, *Supporting Information—Revised Tariff Structure Statement*, 2016.

- 50 per cent of connection capital expenditure
- 2.5 per cent of replacement capital expenditure.

Figure 4: Ergon's direct capital cost distribution[4]



Using these percentages, Ergon apportions an average of 33 per cent of annual capital expenditure to demand growth. When these costs are entered into the LRMC formula, Ergon forecasts between 15 and 60 per cent of its allowable revenue can recovered, based on future demand growth (Table 2).

Table 2: Ergon's LRMC estimates[5]

Distribution system level	LRMC per kVA of demand ($/kVA)	LRMC as a portion of allowable revenue
Sub-transmission	$19–$22	16%–18%
High voltage bus	$66–$78	25%–30%
High voltage line	$198–$236	43%–51%
Low voltage bus	$246–$294	37%–54%
Low voltage line	$308–$368	50%–60%

Our observations on factors that have an impact on Ergon's LRMC are that Ergon:

- has spare capacity in its network.
- has allocated 100 per cent of augmentation capital expenditure to growth in demand.

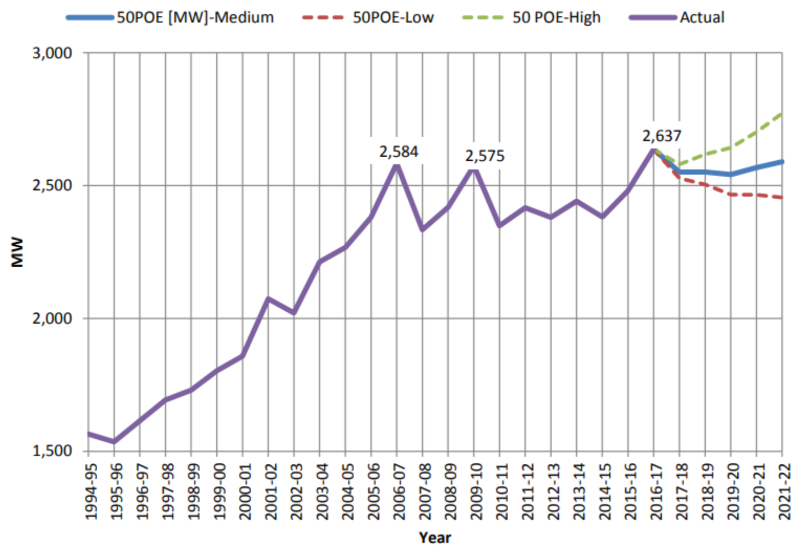
QFF therefore questions the validity of the LRMC approach to setting the level of demand charges and, therefore, demand-based revenues.

Spare capacity

Ergon's annual planning report shows that the total network demand will have low growth up to 2021–22. In Ergon's medium forecast, demand is projected to decrease until 2019–20, and will continue to decrease until 2021–22 under the 'low' scenario.

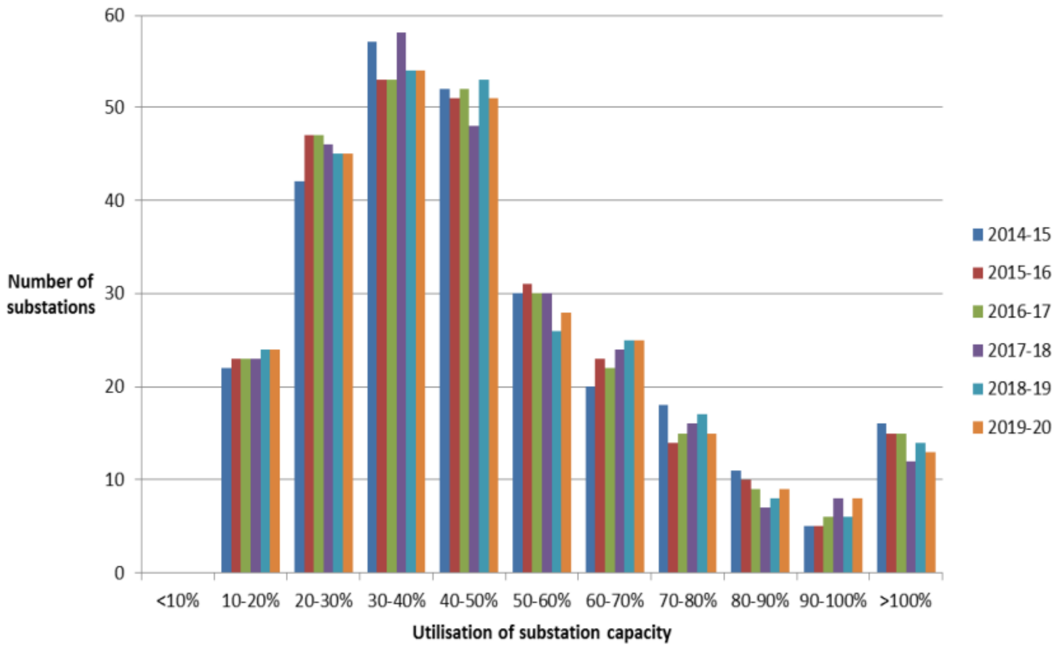
[4] *Electricity Pricing Inquiry*, November 2016. (Ergon Energy determination 2015–20.)
[5] Ergon, *Supporting Information—Revised Tariff Structure Statement*, 2016.

Figure 5 : Ergon system-wide peak demand growth[6]



The presence of spare capacity is also shown in components of the network. For example, in the AER published forecast utilisation of substations in its determination (graph below) only 20 out of Ergon's 252 zone substations are forecast to be above 90 per cent capacity by 2020, which is the trigger for augmentation. Accordingly, 232 zone substations are forecast to be below 90 per cent capacity by 2020.

Figure 6: Zone substation forecast utilisation 2015 to 2020 (without additional augmentation)[7]



Further analysis of Ergon's capital program would increase our understanding of the relationship between spare capacity in Ergon's network and its capital program.

[6] Ergon, *Ergon Energy Distribution Annual Planning Report 2017–18 to 2021–22*, 2017.
[7] AER, *Attachment 6 – Capital expenditure | Ergon Energy determination 2015–20*, 2015.

Apportionment of capex to demand growth

Ergon has allocated 100 per cent of its augmentation to demand growth for its calculation of the LRMC. We note the AER's determination states:

- *The main driver of augex (augmentation capex) is maximum demand and its effect on network utilisation. It can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements*.[8]

Ergon's submission also discusses network augmentation to allow increases in energy usage. Further analysis of Ergon's capital program drivers would increase our understanding of the 100 per cent allocation of augmentation capex to the demand growth driver.

QFF looks forward to further opportunities to participate in Energy Queensland (Ergon and Energex) consultation process to design future network tariffs (2020–25) that meet the needs of Queensland's agricultural sector and current farm design so that our sector can continue to ensure food security. In particular, to work with Energy Queensland to develop cost-reflective demand-based tariff alternatives and we are hopeful that the learnings from the current Agricultural Tariff Trail will provide insight into this process.

If there are any queries regarding this submission, please do not hesitate to contact Dr Georgina Davis at georgina@qff.org.au.

Yours sincerely

Travis Tobin
Chief Executive Officer

[8] AER, *Attachment 6 – Capital expenditure | Ergon Energy determination 2015–20*, 2015.